JC10 Rec'd PCT/PTO 16 NOV 2001

FORM PTO-1390 (REV. 9-2001) U.S DEPARTMENT OF COMMERCE PATENT AND TRADEMARK OFFICE

TRANSMITTAL LETTER TO THE UNITED STATES DESIGNATED/ELECTED OFFICE (DO/EO/US) CONCERNING A FILING UNDER 35 U.S.C. 371

ATTORNEY 'S DOCKET NUMBER
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U.S. APPLICATION NO. (If known, see 37 CFR 1.5
09/979511

INTERNATIONAL APPLICATION NO.	INTERNATIONAL FILING DATE	PRIORITY DATE CLAIMED
PCT/IB00/00654	16 May 2000	60/134,905 f. 19 May 1999

TITLE OF INVENTION
IMPROVED SEISMIC SURVEYING METHOD

APPLICANT(S) FOR DO/EO/US
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Applicant herewith submits to the United States Designated/Elected Office (DO/EO/US) the following items and other information:

1. [XX] This is a **FIRST** submission of items concerning a filing under 35 U.S.C. 371.
2. [ ] This is a **SECOND** or **SUBSEQUENT** submission of items concerning a filing under 35 U.S.C. 371.
3. [ ] This is an express request to begin national examination procedures (35 U.S.C. 371(f)). The submission must include items (5), (6), (9) and (21) indicated below.
4. [ ] The US has been elected by the expiration of 19 months from the priority date (Article 31).
5. [XX] A copy of the International Application as filed (35 U.S.C. 371(c)(2))
   a. [X] is attached hereto (required only if not communicated by the International Bureau).
   b. [ ] has been communicated by the International Bureau.
   c. [ ] is not required, as the application was filed in the United States Receiving Office (RO/US).
6. [ ] An English language translation of the International Application as filed (35 U.S.C. 371(c)(2)).
   a. [ ] is attached hereto.
   b. [ ] has been previously submitted under 35 U.S.C. 154(d)(4).
7. [ ] Amendments to the claims of the International Aplication under PCT Article 19 (35 U.S.C. 371(c)(3))
   a. [ ] are attached hereto (required only if not communicated by the International Bureau).
   b. [ ] have been communicated by the International Bureau.
   c. [ ] have not been made; however, the time limit for making such amendments has NOT expired.
   d. [ ] have not been made and will not be made.
8. [ ] An English language translation of the amendments to the claims under PCT Article 19 (35 U.S.C. 371 (c)(3)).
9. [X] An oath or declaration of the inventor(s) (35 U.S.C. 371(c)(4)).
10. [ ] An English lanugage translation of the annexes of the International Preliminary Examination Report under PCT Article 36 (35 U.S.C. 371(c)(5)).

Items 11 to 20 below concern document(s) or information included:

11. [ ] An Information Disclosure Statement under 37 CFR 1.97 and 1.98.
12. [ ] An assignment document for recording. A separate cover sheet in compliance with 37 CFR 3.28 and 3.31 is included.
13. [ ] A FIRST preliminary amendment.
14. [ ] A SECOND or SUBSEQUENT preliminary amendment.
15. [ ] A substitute specification.
16. [ ] A change of power of attorney and/or address letter.
17. [ ] A computer-readable form of the sequence listing in accordance with PCT Rule 13ter.2 and 35 U.S.C. 1.821 - 1.825.
18. [ ] A second copy of the published international application under 35 U.S.C. 154(d)(4).
19. [ ] A second copy of the English language translation of the international application under 35 U.S.C. 154(d)(4).
20. [ ] Other items or information:

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		CALCULATIONS	PTO USE ONLY
21. [X] The following fees are submitted: **BASIC NATIONAL FEE (37 CFR 1.492 (a) (1) - (5)):** Neither international preliminary examination fee (37 CFR 1.482) nor international search fee (37 CFR 1.445(a)(2)) paid to USPTO and International Search Report not prepared by the EPO or JPO . . . . **$1040.00** International preliminary examination fee (37 CFR 1.482) not paid to USPTO but International Search Report prepared by the EPO or JPO . . . . **$890.00** International preliminary examination fee (37 CFR 1.482) not paid to USPTO but international search fee (37 CFR 1.445(a)(2)) paid to USPTO . . . . **$740.00** International preliminary examination fee (37 CFR 1.482) paid to USPTO but all claims did not satisfy provisions of PCT Article 33(1)-(4) . . . . **$710.00** International preliminary examination fee (37 CFR 1.482) paid to USPTO and all claims satisfied provisions of PCT Article 33(1)-(4) **$100.00**			
ENTER APPROPRIATE BASIC FEE AMOUNT =		$ 890.00	
Surcharge of **$130.00** for furnishing the oath or declaration later than [ ] 20 [ ] 30 months from the earliest claimed priority date (37 CFR 1.492(e)).		$	

CLAIMS	NUMBER FILED	NUMBER EXTRA	RATE		
				$	
Total claims	9 - 20 =	0	x **$18.00**	$	
Independent claims	1 - 3 =	0	x **$84.00**	$	
MULTIPLE DEPENDENT CLAIM(S) (if applicable)			+ **$280.00**	$	
TOTAL OF ABOVE CALCULATIONS =				$ 0.00	
[ ] Applicant claims small entity status. See 37 CFR 1.27. The fees indicated above are reduced by 1/2. +				$	
SUBTOTAL =				$	
Processing fee of **$130.00** for furnishing the English translation later than [ ] 20 [ ] 30 months from the earliest claimed priority date (37 CFR 1.492(f)).				$	
TOTAL NATIONAL FEE =				$ 890.00	
Fee for recording the enclosed assignment (37 CFR 1.21(h)). The assignment must be accompanied by an appropriate cover sheet (37 CFR 3.28, 3.31). **$40.00** per property +				$	
TOTAL FEES ENCLOSED =				$ 890.00	
				Amount to be refunded:	$
				charged:	$

a. [ ] A check in the amount of $ ________________ to cover the above fees is enclosed.

b. [X] Please charge my Deposit Account No. 50-1720 in the amount of $ 890.00 to cover the above fees. A duplicate copy of this sheet is enclosed.

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NOTE: Where an appropriate time limit under 37 CFR 1.494 or 1.495 has not been met, a petition to revive (37 CFR 1.137 (a) or (b)) must be filed and granted to restore the application to pending status.

SEND ALL CORRESPONDENCE TO:

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44,106
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JC10 Rec'd PCT/PTO 16 NOV 2001
09/979511
PCT/IB00/00654

IMPROVED SEISMIC SURVEYING METHOD

Background of the Invention

This invention relates generally to seismic surveying methods, and more particularly to an improved seismic surveying method of using a plurality of vibratory seismic sources.

Seismic vibrators have been used for many years on land to acquire seismic data and many companies have ongoing efforts to utilize similar sources in marine environments. The geophysical and environmental benefits of using these types of seismic sources are well known.

When seismic data is acquired utilizing a plurality of vibratory seismic sources, the vibrators are conventionally organized as a travelling source array. The vibrators are typically placed around or along a source point (also referred to as a "vibrator point" or a "vib point") with a particular separation distance, such as 40 meters. The vibrators then generate a certain number of sweeps that are received by a plurality of seismic sensors, recorded and stacked (i.e. combined) to produce a seismic data trace for each particular source point/receiver point pairing. The vibrators then travel as a group to the next source point where they are used in a similar manner.

There are several known problems with acquiring seismic data using seismic vibrators, however, including the need to acquire large numbers of relatively-long records for each source point/receiver point pair to produce seismic data having a sufficiently high signal to noise ratio. Other known problems with seismic data acquisition using seismic vibrators include harmonics, ground coupling differences, baseplate flexures, and source array effects.

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Efforts have been made to address these problems, and one promising approach has been the simultaneous use of multiple vibrators at different source points, with each vibrator producing separable, encoded sweeps. One method using this approach, referred to as the High Fidelity Vibroseis Source ("HFVS") method, has been developed by Mobil Oil Corporation and Atlantic Richfield Company and is described in U.S. Patent Nos. 5,550,786 (August 27, 1996); 5,570,833 (December 30, 1997); 5,715,213 (February 3, 1998); and 5,721,710 (February 24, 1998), all incorporated herein by reference. The HFVS method was developed primarily to improve the fidelity of vibroseis data.

The HFVS method may be described, in principle, as comprising the following steps:

1. Measuring the vibrator motion S for each vibrator and each sweep, typically using an accelerometer mounted to the vibrator base-plate. The measured signal S is related to the true vibrator output U and a minimum phase transfer function T_1. In the frequency domain, the equation describing the measured signal S is: $S = U^*T_1$.

2. Recording the seismic data R. This seismic data represents the multiplication in the frequency domain between the earth reflectivity E, the vibrator output U and a minimum phase transfer function T_2: $R = U^*T_2^*E$.

3. Obtaining the earth reflectivity at the vibrator location by multiplying the record R with the inverse of the vibrator motion U: $R/U = T_1/T_2^*E$

For an array of 4 vibrators, V_1, V_2, V_3, and V_4, sweeping simultaneously, the geophone response R is described in the frequency domain by the following linear equation: $R = m_{11}^*h_1 + m_{12}^*h_2 + m_{13}^*h_3 + m_{14}^*h_4$. This equation contains 4 unknowns, h_1, h_2, h_3, and h_4 (the earth response at the vibrator positions V_1, V_2,

V_3, and V_4) and contains the known values R (the geophone response) and m_{11}, m_{12}, m_{13}, and m_{14} (the measured signals).

The unknowns h_1, h_2, h_3, and h_4 can be determined if another 3 sweeps are generated at the same locations and if the sweeps are encoded in such a way that the measured signal matrix is invertable. The system of linear equations is:

$$R_1 = m_{11}{*}h_1 + m_{12}{*}h_2 + m_{13}{*}h_3 + m_{14}{*}h_4$$
$$R_2 = m_{21}{*}h_1 + m_{22}{*}h_2 + m_{23}{*}h_3 + m_{24}{*}h_4$$
$$R_3 = m_{31}{*}h_1 + m_{32}{*}h_2 + m_{33}{*}h_3 + m_{34}{*}h_4$$
$$R_4 = m_{41}{*}h_1 + m_{42}{*}h_2 + m_{43}{*}h_3 + m_{44}{*}h_4 .$$

In matrix notation, this can be written as:

$$R = m \times h$$

where

$$R = \begin{bmatrix} R_1 \\ R_2 \\ R_3 \\ R_4 \end{bmatrix}, \ m = \begin{bmatrix} m_{11} & m_{12} & m_{13} & m_{14} \\ m_{21} & m_{22} & m_{23} & m_{24} \\ m_{31} & m_{32} & m_{33} & m_{34} \\ m_{41} & m_{42} & m_{43} & m_{44} \end{bmatrix}, \text{ and } h = \begin{bmatrix} h_1 \\ h_2 \\ h_3 \\ h_4 \end{bmatrix}.$$

The typical implementation of the HFVS method in the field involves one array or group of vibrators, often four, spread out on an equal number of consecutive stations or source points. The vibrators sweep a certain number of sweeps, let say N (N being greater than or equal to the number of vibrators) at the same locations. The sweeps have the same frequency content but the phase is differently encoded to assure that the matrix M is invertible. After N sweeps, the vibrators move up a number of stations equal to the number of vibrators and repeat the sequence.

This implementation of the HFVS method has typically performed well in areas with shallow targets and good signal to noise ratios. For deeper targets or poor signal to noise areas, the standard implementation of the HFVS method may not perform well. The number of traces required for each source/receiver pair (the "fold") is also quite high, making acquisition of seismic data using this method relatively expensive.

It is therefore desirable to implement an improved method of acquiring seismic data using a plurality of vibratory seismic sources that overcomes problems exhibited by prior art seismic data acquisition methods.

An object of the present invention is to provide an improved method of acquiring seismic data using a plurality of vibratory seismic sources.

An advantage of the present invention is that for the same acquisition effort and expense, seismic data having a higher signal to noise ratio may be obtained.

Another advantage of the present method is that if coherent noise in the seismic data is band limited, it may be attenuated only in a particular frequency range, leaving the remaining frequency components of the seismic data unaffected.

Summary of the Invention

The present invention provides an improved method of seismic surveying using a plurality of vibratory seismic sources, the method including the steps of:

deploying at least one seismic sensor;

deploying a plurality of vibratory seismic sources at different source points;

simultaneously actuating said seismic sources;

acquiring seismic data attributable to said seismic sources using said seismic sensor;

redeploying said seismic sources so that at least one of them is positioned at a source point previously occupied by another of them;

simultaneously actuating said redeployed seismic sources;

acquiring seismic data attributable to said redeployed seismic sources using said seismic sensor;

decomposing said acquired seismic data into components attributable to each said seismic source; and

stacking together components attributable to seismic sources located at a common source point.

The invention and its benefits will be better understood with reference to the detailed description below and the accompanying drawings.

Brief Description of the Drawings

Figure 1 is a process flow chart showing steps associated with the inventive method;

Figure 2 is schematic plan view of an exemplary seismic data equipment layout scheme;

Figure 3 is an exemplary amplitude versus frequency plot for a plurality of vibrators;

Figure 4 is a fold distribution and seismic data section produced using a prior art seismic data acquisition method;

Figure 5 is a seismic data section produced using the inventive station-shifting technique; and

Figure 6 is a seismic data section produced using the inventive station-shifting and frequency splitting techniques.

Detailed Description of the Invention

Figure 1 is a process flowchart showing steps associated with the present method. The steps in Figure 1 will be discussed in connection with the schematic plan view of deployed land seismic acquisition equipment shown in Figure 2.

As noted in Figure 1, typically the first step of the method sequence 10 is the "deploy seismic sensor" step 12. In Figure 2, a plurality of seismic sensors 40, often geophones, are shown deployed along a plurality of parallel lines and connected to a data telemetry cable 42 which transmits the output of the sensors to a recording truck 44 where the acquired seismic data is recorded and often initially processed. Figure 2 depicts a typical 3D land seismic survey layout, but it is only one of a vast number of alternative seismic sensor deployment schemes that could be utilized in connection with the inventive method.

Typically the second step of the method sequence 10 is the "deploy seismic sources" step 14. In Figure 2, source points 46 are represented as triangles and four vibrators V_1, V_2, V_3, and V_4 (represented as circles) are being used in this seismic survey. Initially, in this example, vibrator V_1 is located at

source point 48, vibrator V_2 is located at source point 50, vibrator V_3 is located at source point 52, and vibrator V_4 is located at source point 54.

Typically the third step of the method sequence 10 is the "simultaneously actuate seismic sources" step 14, in which all four vibrators are simultaneously actuated to produce four successive sweeps each. In general, if there are N vibrators, each will be actuated to produce M successive sweeps, where M is not less than N. The vibrators will often be both phase and frequency encoded to provide enhanced signal separability. The phase encoding scheme for could, for instance, comprise the following:

	V_1	V_2	V_3	V_4
Sweep 1	90	0	0	0
Sweep 2	0	90	0	0
Sweep 3	0	0	90	0
Sweep 4	0	0	0	90 .

Other methods for phase encoding the vibrator sweeps are described in the references incorporated earlier. This phase encoding assures the invertibility of the vibrator motion matrix.

To enhance the separability of the signals, the sweep bandwidth is split among the vibrators using a frequency splitting technique to provide an additional degree of orthogonality to the source signals. If the sweep bandwidth required in a certain geologic area is between f_1 and f_2 and an array of four vibrators are used to acquire the seismic data, the bandwidth may be split in the following way.

V_1: $[\ f_1,\ f_1 + (f_2 - f_1)/4\ ]$;
V_2: $[\ f_1 + (f_2 - f_1)/4,\ f_1 + (f_2 - f_1)/2\ ]$;
V_3: $[\ f_1 + (f_2 - f_1)/2,\ f_1 + (f_2 - f_1)*3/4\ ]$; and
V_4: $[\ f_1 + (f_2 - f_1)*3/4,\ f_2\ ]$.

Seismic vibrators are, however, typically hydraulically driven mechanical devices that lack the ability to rigidly cut off the production of seismic energy at any particular frequency. Generally they taper or ramp down the energy produced at the highest and lowest desired frequencies. To account for this behavior, referred to as the "sweep taper", a small overlap between the bandwidths for each vibrator may be desirable. This is shown in graphical form in Figure 3.

As discussed above, the desired range of frequencies is divided by the number of vibrators (in this case four) and, in addition, each of the vibrators may be assigned different (and slightly overlapping) frequency ranges. In Figure 3, the desired range of frequencies is from 8 to 97 Hz. By following the frequency separation scheme described above, vibrator V_1 attempts to produce seismic energy matching the first curve 60 (8-31 Hz), vibrator V_2 attempts to produce seismic energy matching the second curve 62 (30-53 Hz), vibrator V_3 attempts to produce seismic energy matching the third curve 64 (52-75 Hz), and vibrator V_4 attempts to produce seismic energy matching the fourth curve 66 (74-97 Hz). The first sweep taper region 68 overlaps the second sweep taper region 70 between 30 and 31 Hz. Similar sweep taper overlaps occur between 52 and 53 Hz and between 74 and 75 Hz.

In terms of separability of the received signals, it would be preferable to eliminate any overlap of these taper zones. In many cases, however, it is desired to produce a source signal that is spectrally flat, i.e. that has substantially the same amplitude over the entire frequency range. If the signal is phase (as well as frequency) encoded, the spectral flatness benefits may overweight the reduction in separability this minor overlapping of the frequency spectra produces. The inventive method does not require that a spectrally flat signal be produced, however. In some cases, for instance, it may be preferable to weight or concentrate the seismic energy with respect to a particular frequency range or ranges, particularly if geologic conditions in a particular area substantially

attenuate reflected seismic energy outside a certain narrow frequency range or ranges.

For each of the four sweeps produced when the seismic sources V_1 to V_4 are simultaneously actuated, the seismic sensors 40 will receive the seismic data in the "acquire seismic data" step 18. The seismic data is typically transmitted back to a recording truck 44 where it is recorded, preferably along with signals from respective accelerometers on each vibrator representative of the vibrator motion.

When the required number of records have been obtained, the seismic sources are redeployed in the "shift seismic sources" step 20. Using one implementation of the station-shifting technique, vibrator V_4 is shifted to source point 56, vibrator V_3 is shifted to source point 54, vibrator V_2 is shifted to source point 52, and vibrator V_1 is shifted to source point 50. The "simultaneously actuate seismic sources" step 22 and the "acquire seismic data" step 24 are then repeated the required number of times for that particular equipment layout.

Typically, the vibrators will continue to produce seismic energy in their assigned split frequency ranges, as discussed above, but other frequency range assignment schemes can easily be envisioned. For source separability reasons, it is important that the frequency range of the seismic energy produced by one simultaneously actuated seismic source be substantially outside the frequency range of the seismic energy produced by another simultaneously actuated seismic source. Preferably at least half of the seismic energy produced by one seismic source occupies a different frequency spectrum than half of the seismic energy produced by another simultaneously actuated seismic source. As noted above, some overlapping of the frequency ranges may actually be desirable, but the purpose of this frequency splitting is to allow the received seismic data to be decomposed into components attributable to different source points based, at least in part, on their differing frequency contents.

Path 26 shows that this process is repeated until the required number of records have been acquired for each vibrator for each source point. The next time the seismic sources are shifted, vibrator V_4 is shifted to source point 58, vibrator V_3 is shifted to source point 56, vibrator V_2 is shifted to source point 54, and vibrator V_1 is shifted to source point 52. After the required number of traces are acquired in this deployment setup, the vibrators are shifted one more station toward the top of Figure 2, and the required number of traces are acquired in this new deployment setup. After completing this fourth acquire seismic data step, it will be appreciated that each of the vibrators (V_1, V_2, V_3, and V_4) have been deployed at source point 54.

Each of the traces acquired by a particular seismic sensor while a vibrator was located at source point 54 will then be decomposed or separated in the "decompose acquired seismic data" step 28. Typically this decomposition process results in individual traces for each sweep each vibrator generated at the particular source point. If four vibrators are used and they each produced four sweeps at the source point, there would be 16 output traces, four each in four separate frequency band groups. Collectively, these four separate frequency band groups cover the entire seismic bandwidth required for the seismic survey.

To increase the signal to noise ratio of the seismic data, these traces are combined ("vertically stacked") in the "stack decomposed seismic data" step 30. The traces may also be filtered prior to this stacking step. In some areas, noise, such as ground roll noise or power line noise, will be frequency band-limited. In these cases it may be desirable, for instance, to filter the frequency-limited traces containing this noise before they are stacked. This may be advantageous because noise attenuation methods may be used on the noise affected data without fearing that the noise attenuation methods may corrupt the seismic signals in the other sweep frequency ranges. This stacking process may consist of merely averaging all of the signals or more sophisticated stacking methods may be used such as the diversity stacking method discussed in U.S. Patent No. 3,398,396 to P. Embree or the covariant stacking method discussed in our PCT

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Patent Application PCT/GB98/03819 (WO 99/32903) to G. Baeten, both of which are incorporated herein by reference. It should be noted that the word "stacking" when used in this context simply refers to combining and does not imply normal moveout correction or reduction to zero offset.

A significant advantage of the inventive method compared to prior art seismic data acquisition methods is that the signal to ambient noise ratio of the seismic data may be significantly improved. The signal to noise ratio of seismic data acquired using vibratory seismic sources may be calculated using the following equation:

Signal/ambient noise = NV*SQRT(NS*L*W)

where:

NV = number of vibrators;
NS = number of sweeps;
L = sweep length; and
W = sweep bandwidth.

By increasing the number of vibrators deployed at each source point (albeit sequentially, not simultaneously), the number of sweeps and the sweep length can both be reduced while simultaneously improving the signal to noise ratio of the acquired seismic data.

The separability of the sources is improved using the split bandwidth technique because the fundamental for each sweep is different and the first order harmonics generated by the third and fourth vibrator do not overlap the first and second sweep frequencies. The inventive method is capable of attenuating not only pneumatically introduced harmonics but also vibrator base-plate/earth interface introduced harmonics.

The amplitude spectrum produced by the vibrators also has larger values for narrow bandwidths and the same sweep length.

Amplitude spectrum = Af*SQRT(T/4*W)

where:

Af = amplitude of the fundamental;
T = sweep length; and
W = sweep bandwidth.

Each of the vibrators is therefore able to transmit a greater quantity of seismic energy into the ground per time unit by limiting the bandwidth swept.

Even if the sweep bandwidth used is the same for each vibrator (i.e. the frequency splitting technique is not used), the vertical stacking/station-shifting method will still improve the signal to ambient noise ratio of the acquired seismic data. When using the vertical stacking/station-shifting technique, any specific vibrator correlated noise will be attenuated because the seismic data associated with the particular source/receiver pair will consist of data associated with each of the vibrators. In addition, the data associated with any particular source/receiver pair will typically be acquired over a larger time window, thereby helping to attenuate any ambient noise that is time variant.

The seismic data produced by the inventive method will then typically be subjected to other seismic data processing techniques such as filtering, migration, etc. that are well known in the seismic data processing art.

The benefits associated with the inventive method were confirmed using both synthetic data and in a field experiment. The results of the field experiment, which was conducted in the Delaware Basin, Ward Country, West Texas, are shown in Figures 4, 5, and 6. It should be noted that in contrast to the 3D

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acquisition geometry shown in Figure 1, these field experiments were conducted using a 2D acquisition geometry, where the sources (vibrators) and the receivers (geophones) are deployed along a common line.

Figure 4 shows the results of a conventional 2D HFVS seismic survey. In this experiment, four vibrators were used, the sweep frequency was from 8 to 96 Hertz, the sweep length was 10 seconds, the number of sweeps produced at each vibrator point was 8, the receiver interval spacing was 200 feet, the shot interval spacing was 50 feet, the listening time after each sweep was five seconds, and the number of stations each vibrator was shifted after completing its sweeps was 4 (200 feet). As can be seen in the fold bar chart 80 at the top of Figure 4, the fold produced by these acquisition parameters is approximately 60. The seismic data were then processed using a standard HFVS processing sequence (separation, spiking deconvolution, NMO correction, derive and apply statics, CMP sort, and stack) to produce the reference seismic data section 82 shown in Figure 4.

This reference seismic data section 82 can be compared against the improved seismic data section 86 shown in Figure 5. In this experiment, many of the parameters used were identical to those used in the previous experiment: four vibrators were used, the sweep frequency was from 8 to 96 Hertz, the receiver interval spacing was 200 feet, the shot interval spacing was 50 feet, and the listening time after each sweep was five seconds. The same vibrators, sensors, and recording equipment were used for this experiment and it was conducted over the same area as the first experiment. The sweep length was, however, reduced from 10 to 4 seconds, the number of sweeps at each vibrator point was reduced from 8 to 4, and the number of stations each vibrator was shifted after completing its sweeps was 1 (50 feet). As can be seen in the fold bar chart 84 at the top of Figure 5, the fold produced by these acquisition parameters was approximately 15 (a four-fold reduction from the previous experiment). The acquired seismic data were then processed using the same processing sequence to produce improved seismic data section 86. Many more coherent reflectors can

be seen in this improved seismic data section 86 than in the reference seismic data section 82.

An experiment was also conducted using both the one-station station-shifting technique and the frequency separation technique. The results of this experiment are presented in Figure 6. The only difference between this experiment and the previous experiment, the results of which are shown in Figure 5, is that the four vibrators used separate sweep frequencies of 8-31, 30-53, 52-75, and 74-97 Hz, as discussed earlier. The fold was therefore unchanged, remaining at approximately 15 as shown in the fold bar chart 88 at the top of Figure 6. It should also be noted that the seismic data section 90 was created using only the 8-31 Hz bandwidth data because the frequency response in the test area was very narrow. The enhanced seismic data section 90 appears to provide an even clearer depiction of the subsurface geology than the improved seismic data section 86.

It will be readily understood that the steps and processes associated with the disclosed embodiment of the present method are capable of a wide variety of alternative implementation methods and only a limited section from an actual seismic survey is discussed above. The described experiments imaged pressure-pressure transmission mode seismic energy, but the method is not limited to this particular seismic energy transmission mode and could, for instance, image pressure-shear converted transmission mode, shear-shear transmission mode, or multi-component seismic data. The seismic data acquired may be inverted using recorded vibrator output (using an HFVS-like method), may be inverted based on a theoretical or optimal vibrator output, or may be processed using other types of processing algorithms. The present method is also in no way limited or restricted to the particular order of steps described above.

CLAIMS

1. A method of seismic surveying using a plurality of vibratory seismic sources, the method including the steps of:

deploying at least one seismic sensor;

deploying a plurality of vibratory seismic sources at different source points;

simultaneously actuating said seismic sources;

acquiring seismic data attributable to said seismic sources using said seismic sensor;

redeploying said seismic sources so that at least one of them is positioned at a source point previously occupied by another of them;

simultaneously actuating said redeployed seismic sources;

acquiring seismic data attributable to said redeployed seismic sources using said seismic sensor;

decomposing said acquired seismic data into components attributable to each said seismic source; and

stacking together components attributable to seismic sources located at a common source point.

2. A method according to claim 1, wherein said simultaneously actuating steps each comprise simultaneously actuating each seismic source M times at each source point, where M is not less than the number of seismic sources.

3. A method according to claim 1 or claim 2, further including the step of noise attenuating at least one of said components before said components are stacked together.

4. A method according to any preceding claim, wherein the respective outputs of said seismic sources are recorded and used in processing said acquired seismic data.

5. A method according to any preceding claim, wherein said seismic data is inverted using theoretical or optimal seismic source output.

6. A method according to any preceding claim, wherein each said seismic source is capable of producing seismic energy within a respective frequency range and the frequency range of the seismic energy produced by one said seismic source is substantially outside the frequency range of seismic energy produced by another said seismic source when said seismic sources are simultaneously actuated.

7. A method according to claim 6, wherein said seismic sources have sweep tapers and a sweep taper of one said seismic source overlaps a sweep taper of another said seismic source.

8. A method according to claim 6 or claim 7, wherein the frequency range of one said seismic source has first order harmonics that do not overlap the frequency range of another said seismic source.

9. A method according to any preceding claim, wherein said redeploying step comprising shifting said seismic sources one said source point in a common direction along a common path.

Fig.1.

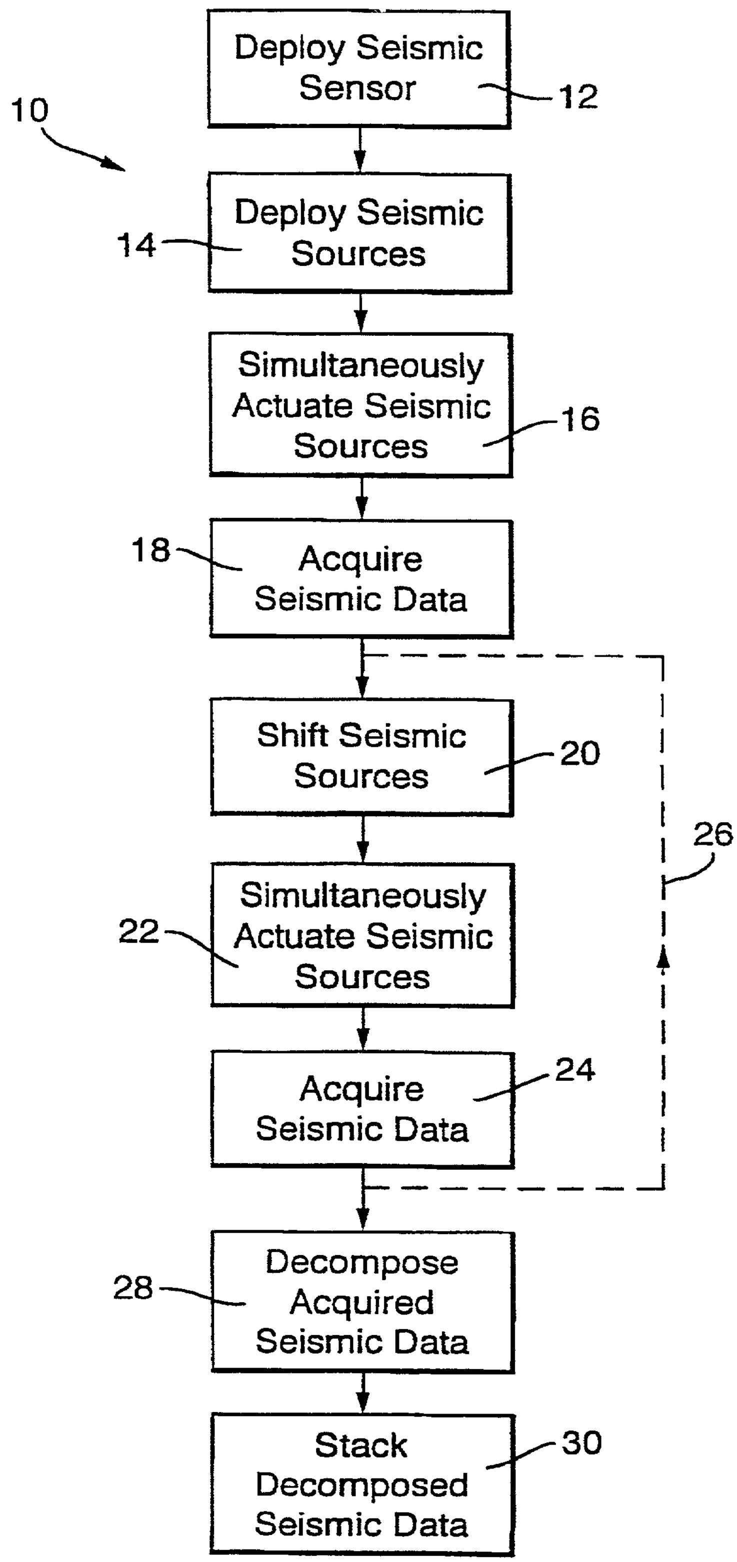

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Fig.2.

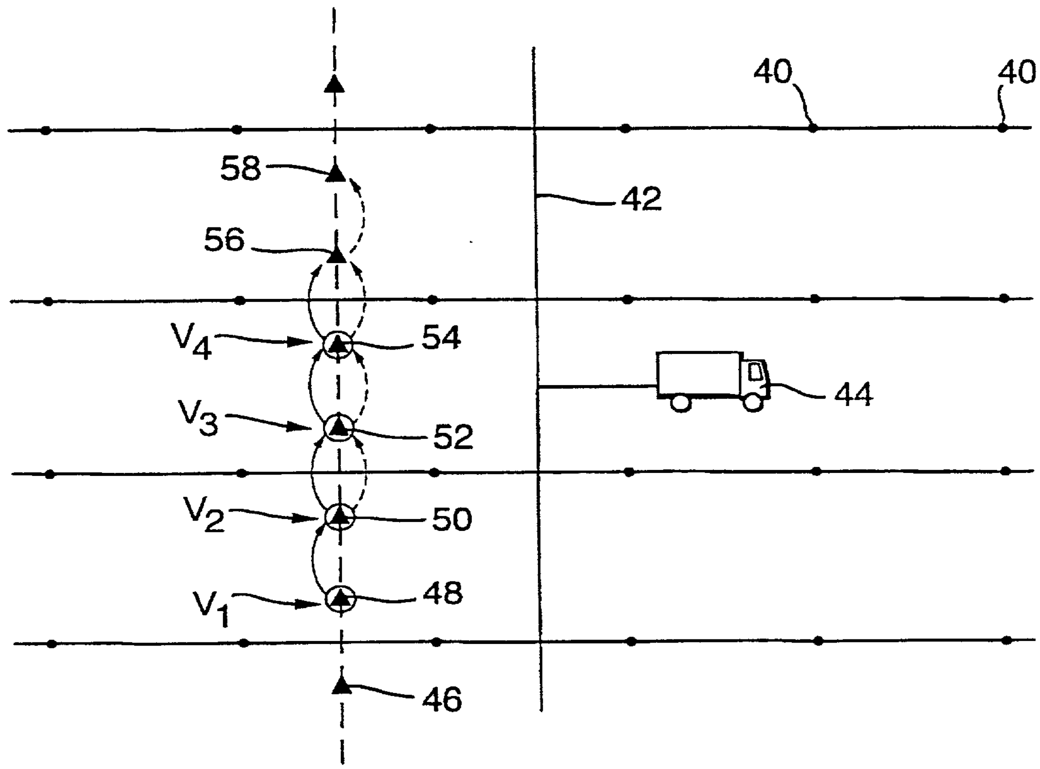

Fig.3.

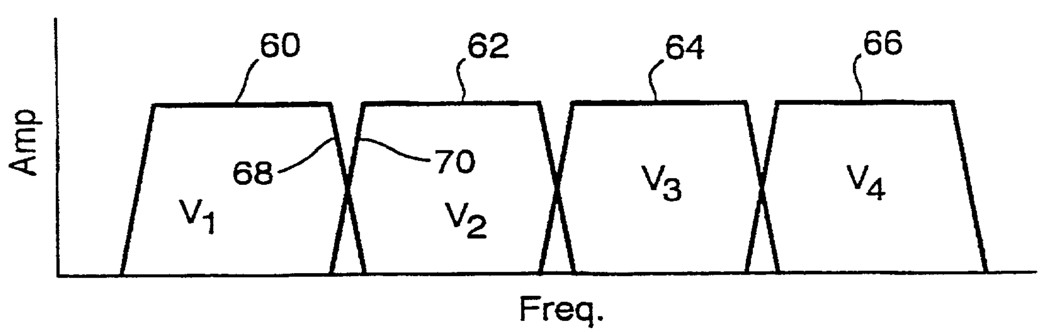

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Fig.4.

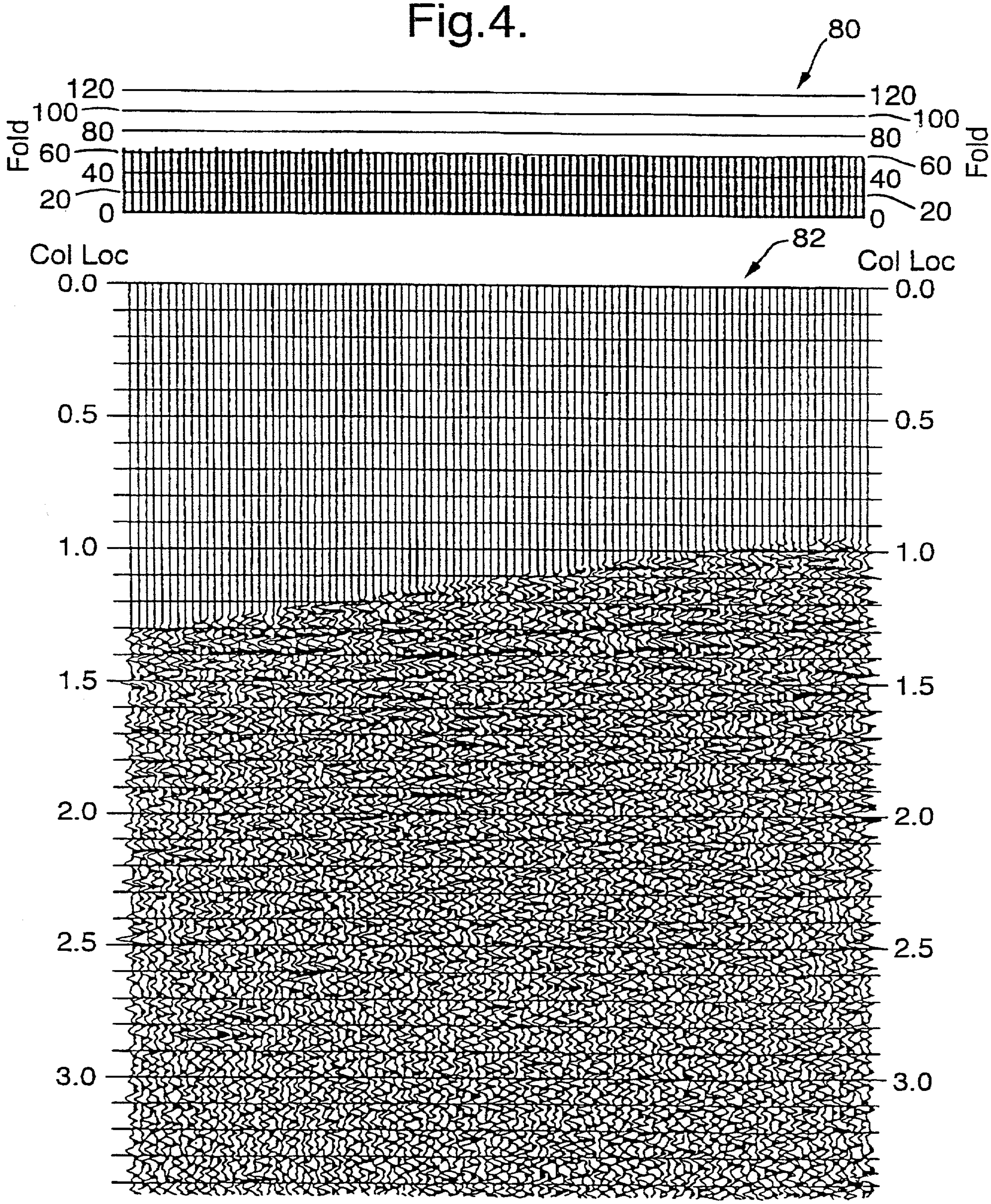


Fig.5.

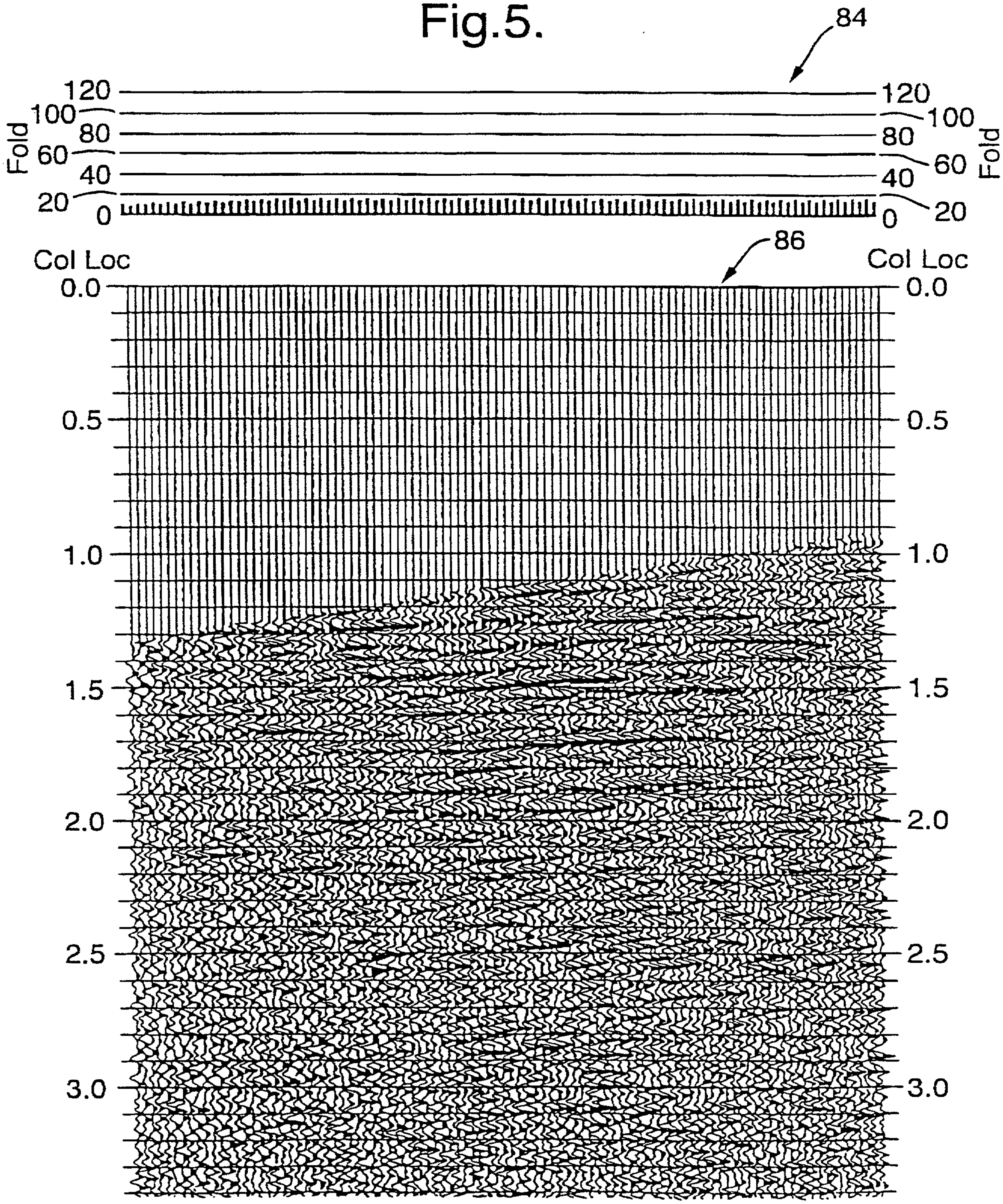
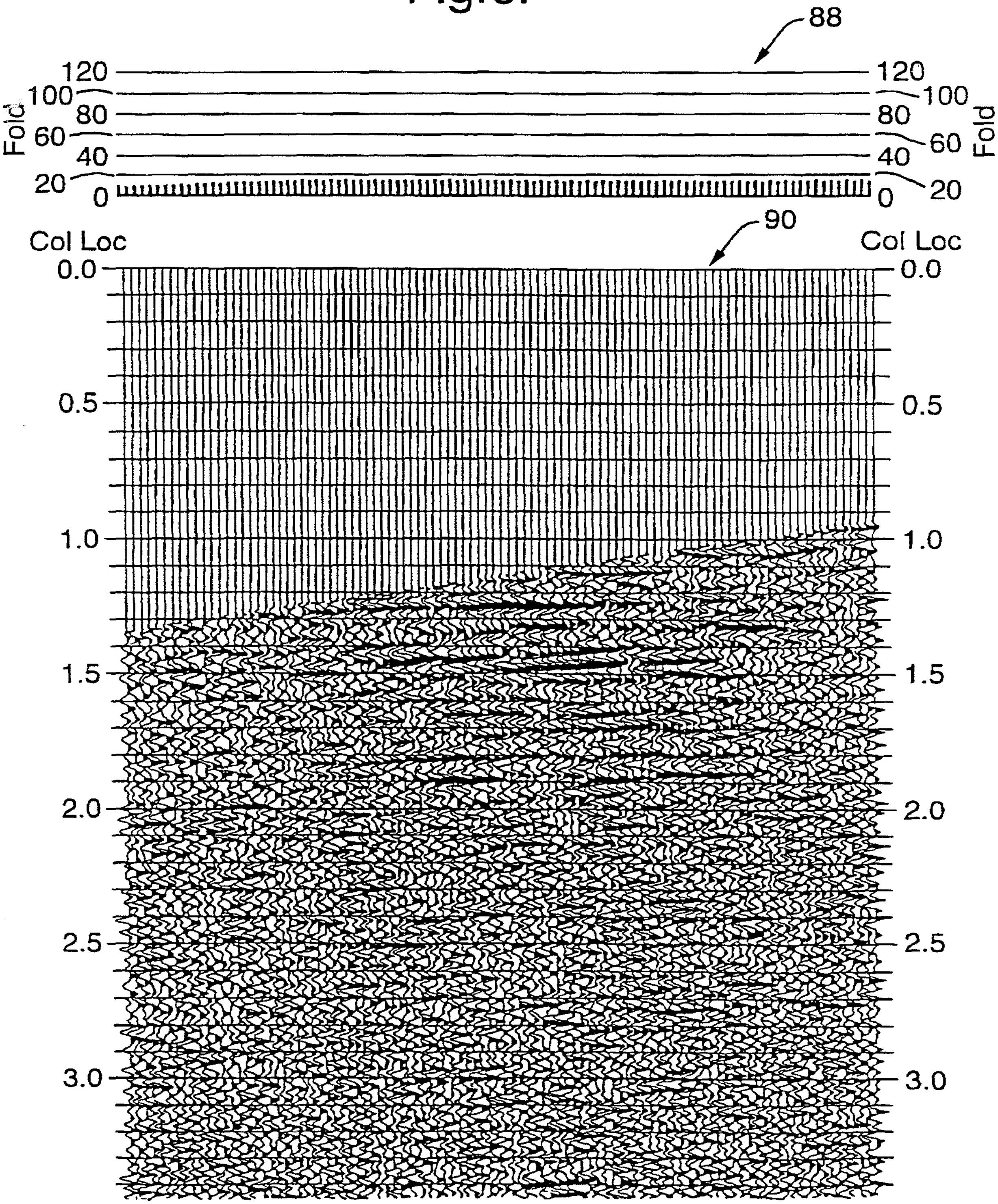


Fig.6.



Declaration and Power of Attorney for Patent Application

English Language Declaration

As a below named inventor, I hereby declare that:

My residence, post office address and citizenship are as stated below next to my name,

I believe I am the original, first and sole inventor (if only one name is listed below) or an original, first and joint inventor (if plural names are listed below) of the subject matter which is claimed and for which a patent is sought on the invention entitled:

IMPROVED SEISMIC SURVEYING METHOD

the specification of which

(check one)

    is attached hereto

x   was filed on 16 May 2000 as Application Serial No. PCT/IB00/00654
    and was amended on ____________________ (if applicable)

I hereby state that I have reviewed and understand the contents of the above-identified specification, including the claims, as amended by any amendment referred to above.

I acknowledge the duty to disclose information which is material to the examination of this application in accordance with Title 37, Code of Federal Regulations, δ1.56(a).

I hereby claim foreign priority benefits under Title 35, United States Code, Section 119 of any foreign application(s) for patent or inventor's certificate listed below and have also identified below any foreign application for patent or inventor's certificate having a filing date before that of the application on which priority is claimed:

Prior Foreign Application(s)			<u>Priority Claimed</u>	
________ (Number)	________ (Country)	________ (Day/Month/Year Filed)	Yes	No
________ (Number)	________ (Country)	________ (Day/Month/Year Filed)	Yes	No
________ (Number)	________ (Country)	________ (Day/Month/Year Filed)	Yes	No

I hereby claim the benefit under Title 35, United States Code, §120 of any United States application(s) listed below and, insofar as the subject matter of each of the claims of this application is not disclosed in the prior United States application in the manner provided by the first paragraph of Title 35, United States Code §112, I acknowledge the duty to disclose material information as defined in Title 37, Code of Federal Regulations, §1.56(a) which occurred between the filing date of the prior application and the national or PCT international filing date of this application.

60/134,905	16 May 2000	
(Application Serial No.)	(Filing Date)	(Status) (patented,pending, abandoned)
(Application Serial No.)	(Filing Date)	(Status) (patented,pending, abandoned)

I hereby declare that all statements made herein of my own knowledge are true and that all statements made on information and belief are believed to be true; and further that these statements were made with the knowledge that willful false statements and the like so made are punishable by fine or imprisonment, or both, under Section 1001 of Title 18 of the United States Code and that such willful false statements may jeopardize the validity of the application of any patent issuing thereon.

POWER OF ATTORNEY: As a named inventor, I hereby appoint the following attorneys and/or agents to prosecute this application and transact all business in the Patent and Trademark Office connected therewith (list name and registration number)

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